California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Overview of the Risks of Geologic CO_2 Storage

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CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

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Monitoring, Verification, and Reporting Overview

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Options for Permitting Carbon Capture and Sequestration Projects in California

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Introduction

An understanding of the risks associated with geologic CO_2 storage is fundamental to the development of regulations that ensure protection of workers, the general population, the environment, and natural resources. Although the idea of intentionally storing large quantities of CO_2 in underground geologic formations for extended periods is relatively new, industrial operations, including petroleum exploration and production, enhanced oil recovery using CO_2, underground gas storage, and disposal of acid gas and hazardous wastes, provide many decades of relevant knowledge and experience for determining the risks of geologic storage, as well as the methods and technology to mitigate those risks. Using this knowledge as a basis, many studies have been undertaken over the last decade to determine the specific risks associated with geologic storage. There is a general consensus among the technical community, as evidenced by the *IPCC Special Report Carbon Dioxide Capture and Storage*[1] and many other papers, that through proper site selection, characterization, operation, and closure, geologic storage of CO_2 can be carried out without adverse environmental, health or safety impacts. The relatively small number of projects that have been undertaken to date specifically for purposes of CO_2 storage have thus far confirmed this conclusion.

Storage Project Risks

Geologic storage projects entail the usual risks associated with the construction and operation of large industrial projects. Storage projects will involve laying pipelines and drilling deep wells. Employees and contractors will be working outside in remote locations with large, heavy, equipment. The process of digging trenches for pipelines entails worker safety risks as well as risks to the environment. Similarly, well drilling entails risks to workers from conditions encountered in the subsurface as well as to the environment, due to construction of the drill site. These risks need to be assessed, managed, and mitigated, but will not be discussed further under the assumption that they are well understood in the context of common industrial operations.

For the remainder of the paper, discussion will focus on the risks of storage which derive particularly from the properties of CO_2 and its effect on the environment when injected. CO_2 is non-toxic and nonflammable; we exhale CO_2 when we breathe, and plants uptake CO_2 for photosynthesis. Though high concentrations of CO_2 in the atmosphere are easily dispersed by air currents, if a high concentration is allowed to persist, it can displace breathable air, posing a risk of asphyxiation in humans and animals. High concentrations in the soil will cause stress and can eventually kill vegetation. CO_2 is somewhat soluble in water, which produces the "fizz" in beer, soft drinks, and mineral water. The mild acid formed from this dissolution, however, can corrode steel and dissolve cement and rock. In the subsurface, reactions between the CO_2 in the pore water and the surrounding rock can result in the release of organic and inorganic compounds into the water. Since CO_2 will be transported and injected under elevated pressure, risks accompanying compressed gas transport and injection must be considered.

Many of the risks of geologic storage are associated with the potential for leakage, during pipeline transport or during deep subsurface storage. In order for CO_2 stored in the deep

[1] *IPCC Special Report on Carbon Dioxide Capture and Storage,* published for the Intergovernmental Panel on Climate Change, Cambridge University Press, New York, NY, 2005.

subsurface to have an adverse impact on humans, animals, vegetation, groundwater or other resources, it must reach these locations via a pathway. The primary paths for leakage from a deep reservoir would be improperly installed and/or abandoned wells, and undiscovered geologic discontinuities such as faults. There are two primary driving forces to move CO_2 upward along leak paths. The first is pressure – CO_2 must be injected at a pressure greater than the pressure in the fluids already present in the rock. The second is buoyancy – in most cases CO_2 will be less dense than the fluids already present in the rock, and will therefore try to rise upward. It should be noted that these driving forces do not remain constant over the life cycle of a storage project. After injection stops, fluid pressures in the reservoir will begin to decrease, approaching pre-injection levels. The amount of pressure recovery depends on many factors, including the size of the reservoir, and the hydrologic conditions at the boundaries of the reservoir. Buoyancy forces do not decrease, but the amount of CO_2 subject to buoyancy will decrease, both during the injection phase of a storage project and after injection stops. Over time, several processes, referred to as secondary trapping mechanisms, work to immobilize the CO_2 in the reservoir, including physical (capillary trapping) and chemical (solubility and mineral trapping) processes. After the CO_2 is immobilized, buoyancy forces are no longer a factor.

Wellbores that intersect the storage formation potentially provide a direct, short-circuit leakage pathway between the reservoir, groundwater, any other resources that might be above the reservoir, and the surface. Pre-existing wellbores are considered to present a higher risk for leakage than new wellbores because of uncertainty about their condition. The most vulnerable part of a well with regard to leakage is the annular space outside of the casing. After a well is drilled, a steel tube – the casing – is inserted in the hole and cement is pumped into the annular space between the casing and the rock. If the space is not filled completely, CO_2 could migrate upward, potentially all the way to the surface, but more likely into the well through joints in the casing.

The second major category of potential leak paths is subsurface geologic structural features, of which fractures and faults are considered to represent the greatest risks, although there are other subsurface structural features which can create a pathway for leakage (see Figure 1). Fractures, which are essentially cracks in the rock, could provide leak paths if they are present in the sealing formations overlying the reservoirs intervals where CO_2 is stored. Fractures form as a result of natural tectonic processes, but they can be induced if injection pressures are too high. It is unlikely that a single fracture would extend all the way from the reservoir to the surface, so a leakage pathway involving fractures would likely consist of a network of fractures or fractures in conjunction with some other pathway.

Faults are cracks where the two surfaces forming the crack have experienced relative movement, or slip. Faults can exist at all scales, and can therefore provide potential leak paths that extend from the reservoir to the surface. It is noted, however, that faults can also be effective seals and traps for CO_2 storage.

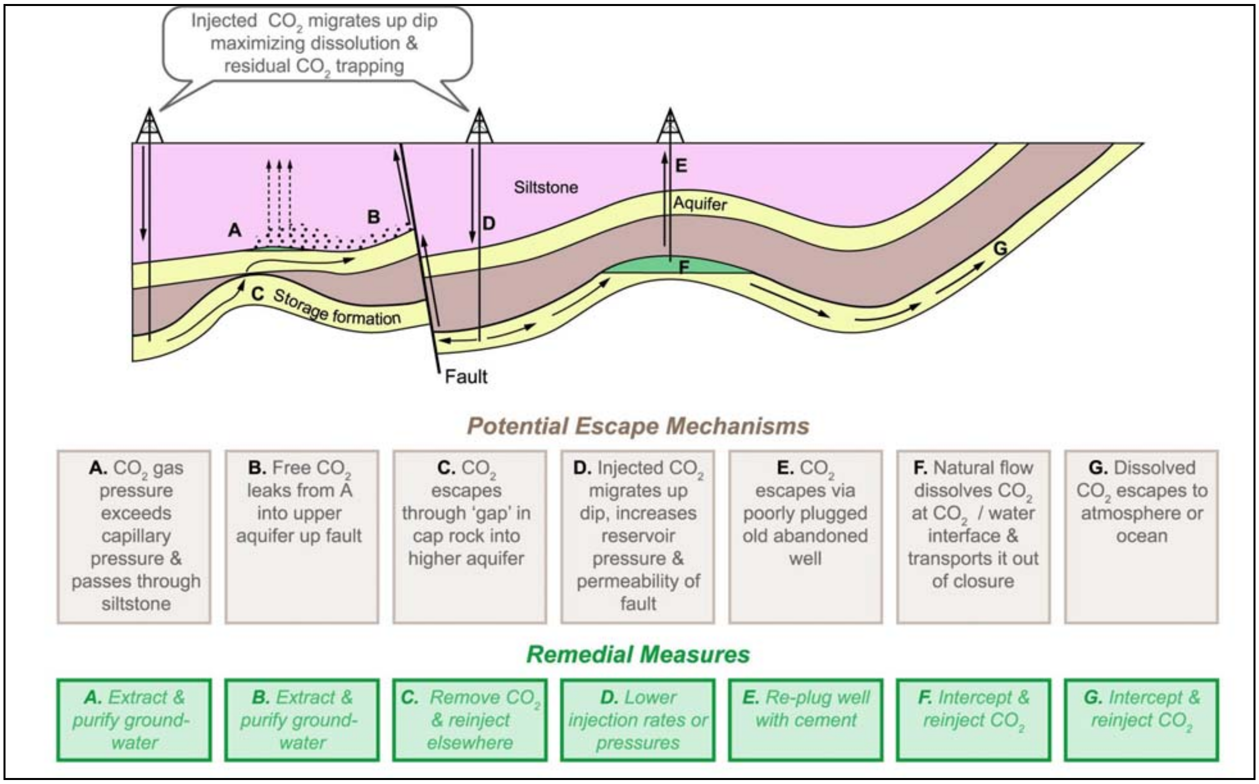

Figure 1 Potential leakage routes and remediation techniques for CO_2 injected into saline formations[2]

Because the CO_2 in pipelines, surface injection facilities, and injection wells will be at high pressure, the risks associated with industrial compressed gas operations must be considered. CO_2 is not flammable, so fire in the event of a sudden release is not a risk; however, a high-velocity (explosive) release of CO_2 could cause damage, injury, or death.

Seismicity induced by injection results from increases in the pressure in the water in the rock, which if high enough, can cause the rock to fracture or cause slip on pre-existing faults and fractures. If the area of slip is large enough, damage from shaking at the surface can result. Public awareness and sensitivity to earthquakes will likely result in special attention being paid to the risks of induced seismicity. The major concern is that CO_2 injection will cause earthquakes that people can feel and that cause some harm. In fact, the number of natural seismic events that are not felt by the public far exceeds the number which are felt, and the same can be said for seismicity induced by subsurface operations. To date, there are no documented instances in which CO_2 injection has induced seismicity that caused harm. Nonetheless, there are a number of well- documented cases to show that subsurface pressure increases, either from direct injection of fluids in the subsurface for waste disposal and geothermal energy development or from impoundment of large volumes of water at the surface in reservoirs, have caused seismicity that people felt, and in some rare instances, caused harm.

When CO_2 is injected, some of it dissolves in the water that is in the rock, however, the injection also causes the pre-existing fluids to become compressed and displaced in order to make room for the CO_2. In saline formation storage, the movement of the displaced saline water can pose a

[2] Ibid.

contamination risk to groundwater and other resources, if a pathway connecting the resource to the saline water exists.

Mitigation of Storage Risks

All the risks of geologic storage can be mitigated by careful site selection and characterization, proper injection practices, and careful monitoring during injection operations and after injections stops. Confidence in the ability to mitigate storage risks, and the methods, tools, and approaches derives from many decades of experience in analogous industrial operations, including petroleum exploration and production, enhanced oil recovery using CO_2, underground gas storage, and disposal of acid gas and hazardous wastes. Convincing the public that a sufficient level of risk mitigation can be achieved remains a challenge.

Site Selection and Characterization

Not all locations in the subsurface are good for storage, so careful site selection and characterization of the subsurface geology are key to mitigation of risks. Knowledge of how hydrocarbons have accumulated and remained trapped for millions of years provides a basis for defining the geologic attributes of storage sites that will prevent leakage. The goal of site selection and characterization is to find sites with those same attributes. Geologic attributes mitigating the risk of leakage include the presence of a thick, unfractured, low-permeability seal. The presence of structural closure, required for hydrocarbon accumulation, is not essential for CO_2 storage because of the action of secondary trapping mechanisms. Faults can be good if they form barriers to leakage, bad if they can conduct CO_2 *and* provide a potential pathway out of the storage reservoir.

Available technologies that can provide the information needed for site selection and characterization include geologic mapping, seismic surveying supported by other geophysical technologies, and wells, both historical and drilled for purpose. It is impossible, however, to interrogate the subsurface at a sufficient level of detail to remove absolutely all uncertainty about properties and structure—hence the need for monitoring.

A part of site selection and characterization in California should be to establish the natural seismicity in the area of a potential site and to assess the change, if any, in seismicity due to the project. This involves both identifying existing faults and evaluating the potential for damaging shaking that might result from an earthquake. Probabilistic seismic hazard analysis (PSHA), the methodology most commonly employed in California to do this, forms the framework for an approach to evaluate the change in seismic hazard, if any, due to a CO_2 storage project.

Construction and Operating Practices

Proper construction of transport and injection facilities will mitigate many geologic storage risks. For pipeline transport, the development of pipeline complex to deliver CO_2 to the Permian Basin, Texas, CO_2 EOR operations in the 1970s motivated the promulgation of best practices and regulations. The most significant risk associated with pipeline transport is leakage, and a variety of methods are in place to mitigate this risk. The recently completed Dakota Gasification Company pipeline has a capacity of 5 million tons a year and carries CO_2 that also contains 0.8%–2% H_2S. Any pressure drop resulting from a significant leak activates block valves, which are situated along the length of the pipeline and therefore limit the volume of the leak. The entire pipeline and compression operations are monitored by telemetry.[3] The pipeline has also been designed for internal inspection by devices to detect corrosion or other defects.

Proper well construction will be essential in mitigating leaks. Decades of experience in commercial CO_2 EOR operations provide a substantial knowledge base of construction methods and technologies, though questions remain about the need for more conservative approaches, as proposed in the EPA Class VI rules, for storage wells. Some key technical issues are associated with the specifications for the casing and the cement used to fill the annular space behind the casing. Discussions continue about whether to use corrosion resistant steels and cement and to fill the annular space from top of the well to the bottom.

Monitoring

Some uncertainty about subsurface conditions and properties will always remain at the end of the characterization phase. Likely sources of uncertainty relevant to storage risks are the potential presence of fractures in the seal, hydrologic properties of faults, in-situ stress state, and hydrologic boundary conditions. There will also be uncertainty in predictions of the area occupied by the CO_2 and the pressure increases caused by injection. A monitoring program provides two types of data that are important to risk mitigation. First, measurements provide direct evidence when something goes wrong—a leak, for example. Since leaks to the surface due to faults or fractures or other geologic pathways are not expected to happen suddenly, early detection also mitigates the risk of serious impacts. The second use of monitoring data is to reduce uncertainty in the geologic model, and increase confidence in predictions of pressures and CO_2 movement, both of which reduce risks.

Many of the measurement technologies for monitoring geologic storage are drawn from other applications such as the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, safety procedures for industries handling CO_2, and ecosystem research. These established practices provide numerous measurement approaches and options—a monitoring toolbox—which enables development of tailored, flexible monitoring programs for geologic storage. The reader is referred to another paper prepared for the California Carbon Capture and Storage Review Panel on measurement, verification, and reporting, for further discussion of monitoring methods and techniques.

Role of Risk Assessment and Risk Management

Risk assessment and risk management are two key elements of risk mitigation and should be part of all projects. Fundamental to risk assessment is a process that identifies risks and rates each risk on the likelihood that an event will happen and the severity of that event should it occur. Each risk is then scored based on the two ratings. The outcome of the assessment is an overall ranking of the risks. In the process of risk management, specific project-related actions

[3] Duncan, I. J., Nicot, J.-P., and Choi, J.-W., 2009, *Risk Assessment for future CO_2 Sequestration Projects Based CO_2 Enhanced Oil Recovery* in the U.S., Proceedings of the 9th Greenhouse Gas Technology Conference, ScienceDirect, Elsevier Ltd., Energy Procedia, pp. 2037–2042.

are identified to mitigate the risks. The process is not static, but evolves over time as new information and confidence is gained about the subsurface.

The need for risk assessment and management is not unique to geologic storage. Over the past ten years, considerable effort has been devoted to tailoring and adapting risk assessment approaches to geologic storage. As a result, there are now commercially available "packages" specifically for geologic storage, although development of risk assessment tools remains an active area of research.

Industrial- and CCS-Specific Experience

What is defined as a significant risk involves an assessment of both the likelihood and severity of an event, however these parameters are difficult to define from a strictly theoretical basis. Case history experience and data is extremely valuable in helping to identify the types of events that are most likely to occur, as well as the impacts of those events. Case history data provide a basis for developing mitigation approaches and technologies to further reduce risks in the future.

Natural gas storage reservoirs are, in many ways, analogous to CO_2 storage projects. A 2005 study[4] found that of the approximately 600 natural gas storage projects operated in the United State, Canada, and Europe, only nine were identified as having experienced leakage: three from caprock issues, five from well bore integrity issues, and one from poor site selection (too shallow). Well integrity issues accounted for most leakage incidents with poor cement jobs, corrosion, and improperly plugged old wells as specific causes.

Recent studies of oil and gas field experience also point to well integrity issues as primary causes for leakage. A study of oil and gas wells in Alberta, Canada,[5] found an overall leakage occurrence rate of about 4.5%, where leakage flow had been identified as from either the formation through the cement behind casing into the well, or from flow outside the casing to surface. A study of CO_2 EOR experience in the Permian Basin, Texas,[6] found that a major cause of wellbore leakage was failure of mechanical components in the injection equipment and loss of control during "work-over", or well maintenance operations.

To date, there have been a relatively small number of projects worldwide dedicated to demonstration of CO_2 storage. All of these projects, however, have been subject to the same risks identified in the beginning of this paper, and none have experienced any adverse impacts. These projects provide several lessons learned relevant to risk mitigation.

Statoil's Sleipner project is the world's first commercial CO_2 storage project. Located offshore in the North Sea, it has been injecting about a million tons of CO_2 per year since 1999. The CO_2 is produced along with natural gas from a deep reservoir. It is removed from the natural gas in

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[4]Perry, K., 2005, "Natural gas storage industry experience and technology: potential application to CO_2 geological storage," Chapter 9 in: *Carbon dioxide capture for storage in deep geologic formations: results from the CO_2 capture project*, Volume II, S. Benson and D. Thomas, eds, Elsevier Science, London.

[5]Watson, T., and S. Bachu, 2009, "Evaluation of the potential for gas and CO_2 leakage along wellbores," SPE 106817, presented at the E&P Environmental and Safety Conference, Galveston, TX.

[6] Op. cit. Duncan, I.J.

offshore facilities and re-injected in a saline formation located about 3000 ft beneath the seafloor. The project is notable because of the successful application of 3D time-lapse seismic surveying as a monitoring tool. The seismic measurements, repeated about every 2 years, have shown the vertical and lateral spread of the CO_2 and have confirmed that the reservoir is not leaking.

The In Salah project, onshore in Algeria, is another commercial storage project in which CO_2 is produced along with natural gas, removed, and re-injected into a saline formation. About 800,000 to 1 million tons per year are injected. This project has an interesting case history because a small amount of leakage occurred from a suspended (not used) appraisal (exploration) well with the designation of KB5. The small amount of leakage was not measured, but was estimated by the operators to be less than 1 metric ton. Due to the extremely remote desert location, there is no vegetation, residents, or wildlife to be adversely impacted by a leak of any size in the vicinity of the well.

KB5 was drilled by Total in 1980. When Total relinquished their hydrocarbon lease, ownership of the well reverted to the State. When the In Salah Gas Joint Venture (BP, Sonatrach, Statoil), referred to as the In Salah JV, was formed, ownership of KB5 (and other legacy wells) remained with the State. Under Algerian hydrocarbon regulations, suspended wells should be decommissioned within two years.

The KB5 well intersected the Carboniferous formation, which was the same formation into which CO_2 would be injected. It was not plugged with cement in the Carboniferous, because, at the time it was drilled, it was a hydrocarbon exploration well, and cementing was not required if hydrocarbons were not found.

Using available data, during the design phase of the JV project in 2001, reservoir simulations indicated that CO_2 would not migrate very far in the direction of KB5. After injection started and monitoring data became available, additional simulations, coupled with satellite observations of surface deformation in 2006 and 2007 suggested that CO_2 was migrating quickly in the direction of KB5. Based on this information, a close inspection of the well was carried out during a routine surveillance visit. (The well is located in an insecure area and military escort is required for site visits.) The presence of CO_2 was detected by a leak through a missing flange. Ideally, presence of CO_2 in the well would have been detected by pressure on a gauge without any leak, but both the flange and the gauge had been stolen.

Though it is unfortunate that a leak occurred at all, this case history illustrates the value and use of surveillance and monitoring data to mitigate risk.

Induced seismicity was introduced as a risk in the initial section of this paper. Monitoring for seismicity has taken place at the Weyburn project in Canada and the Otway project in Australia. The intent of collecting the data on seismicity was to help monitor the movement of the CO_2 in the reservoir. No seismicity of sufficient amplitude to be felt at the surface was expected and none was observed.

Summary

CO_2 storage projects entail the usual risks associated with the construction and operation of an industrial project. The primary concern regarding storage is leakage, which could result in groundwater contamination, localized damage in the soil layer, significant release to the atmosphere, or health hazards. The pathways for leakage potentially include the handling of

CO_2 en route to the injection site, issues with well integrity, and migration through faults or fracturing of the seal. An additional concern is induced seismicity. All the risks of geologic storage can be mitigated by careful site selection and characterization, proper injection practices, and monitoring during injection operations and after injections stops. Confidence in the ability to mitigate storage risks and in the methods, tools, and approaches for doing so derive from many decades of experience in analogous industrial operations. The relatively few projects that have been undertaken to date specifically for purposes of CO_2 storage have been carried out without adverse impacts.